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9. POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

Facility Information

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9.1 Post-Injection Site Care and Site Closure Approach

This Post-Injection Site Care and Site Closure (PISC-SC) Plan describes the activities that Heartland Greenway Carbon Storage, LLC (HGCS) will perform to meet the requirements of 40 CFR 146.93 of the Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells Final Rule (Class VI

Rule) published in December 2010. HGCS will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 15 years post-injection. The PISC-SC plan provides an overview of the post-injection computational modeling, plan for post-injection monitoring, and a site care and site closure plan pursuant to 40 CFR 146.93. The computational modeling overview will discuss methods used to determine the aerial extent of the CO_2 plume and the pressure differential during the post-injection phase. Detailed descriptions of the computational modeling results are discussed in the Area of Review (AoR) and Corrective Action Plan. The results of the modeling determine the necessary monitoring, site care, and timeframe needed during the post-injection phase.

HGCS plans to convert all injection wells to monitoring wells during the post-injection phase of the project to better monitor the plume and pressure front evolution. HGCS may not cease post-injection monitoring until a demonstration of non-endangerment of Underground Sources of Drinking Water (USDWs) has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, HGCS will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation. All records collected during the post-injection period will be retained by HGCS for 10 years following site closure.

9.2 Pre- and Post-Injection Pressure Differential

The maximum pressure plume shown in **Figure 9-1** occurs 30 years after the initiation of injection and represents the project AoR. A calculated pressure threshold of 135 psi is used to define the extent of the AoR. Details of the pressure threshold calculation can be found in the AoR and Corrective Action Plan of this application. Changes in pressure relative to initial reservoir conditions were calculated from simulation results to identify the project AoR, delineating the monitoring area. Predicted reservoir pressure, 0.433 pounds per square inch (psi) a foot MSL prior to injection is considered the initial pressure. Reservoir pressure measurements taken prior to injection can be used to further refine the initial pressure measurement. Simulations were conducted for 30 years of injection in six wells at a rate of one million metric tons per year per well. Simulations were continued for a total of 100 years after the cessation of injection to represent CO_2 plume and pressure front evolution. The pressure buildup in the reservoir is presented in the figures below. A maximum pressure buildup of 370 pounds per square inch (psi) occurred in layer 77 of the model (**Figure 9-2**) at NCV INJ 3 (**Figure 9-3**) 30 years after the initiation of injection. Simulation results show injection well pressure differentials dropping from 370 psi at cessation of injection to 20 psi 15 years post injection well below the 135 psi pressure threshold. The exponentially decreasing pressure differential falls below the pressure threshold of 135 psi 5 years after the cessation of injection.

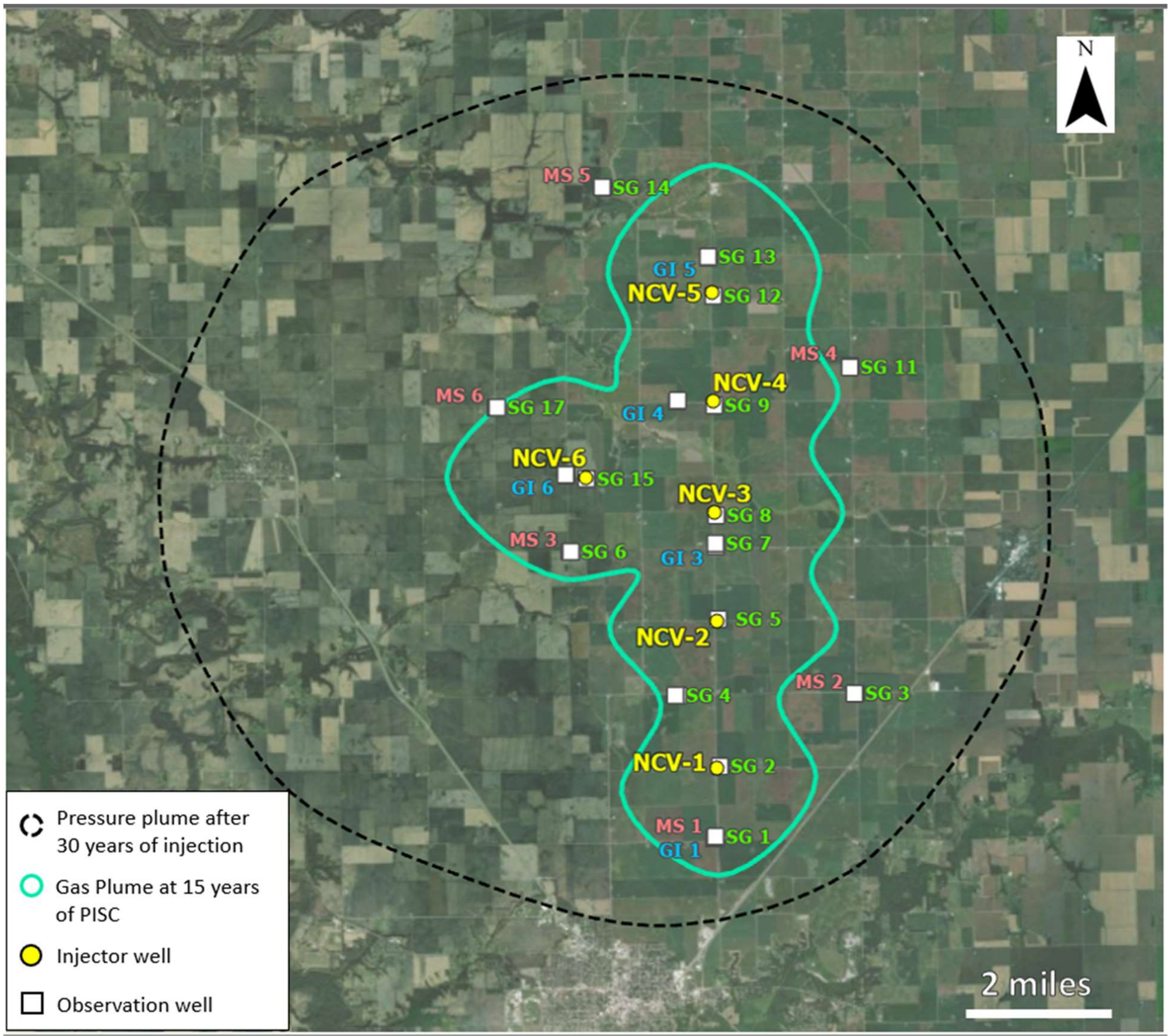

Figure 9-1. AoR highlighting well locations, the pressure plume maximum extent at the end of injection, and the gas plume at 15 years of PISC. All injection wells (yellow) will be converted to monitoring wells after the cessation of injection.

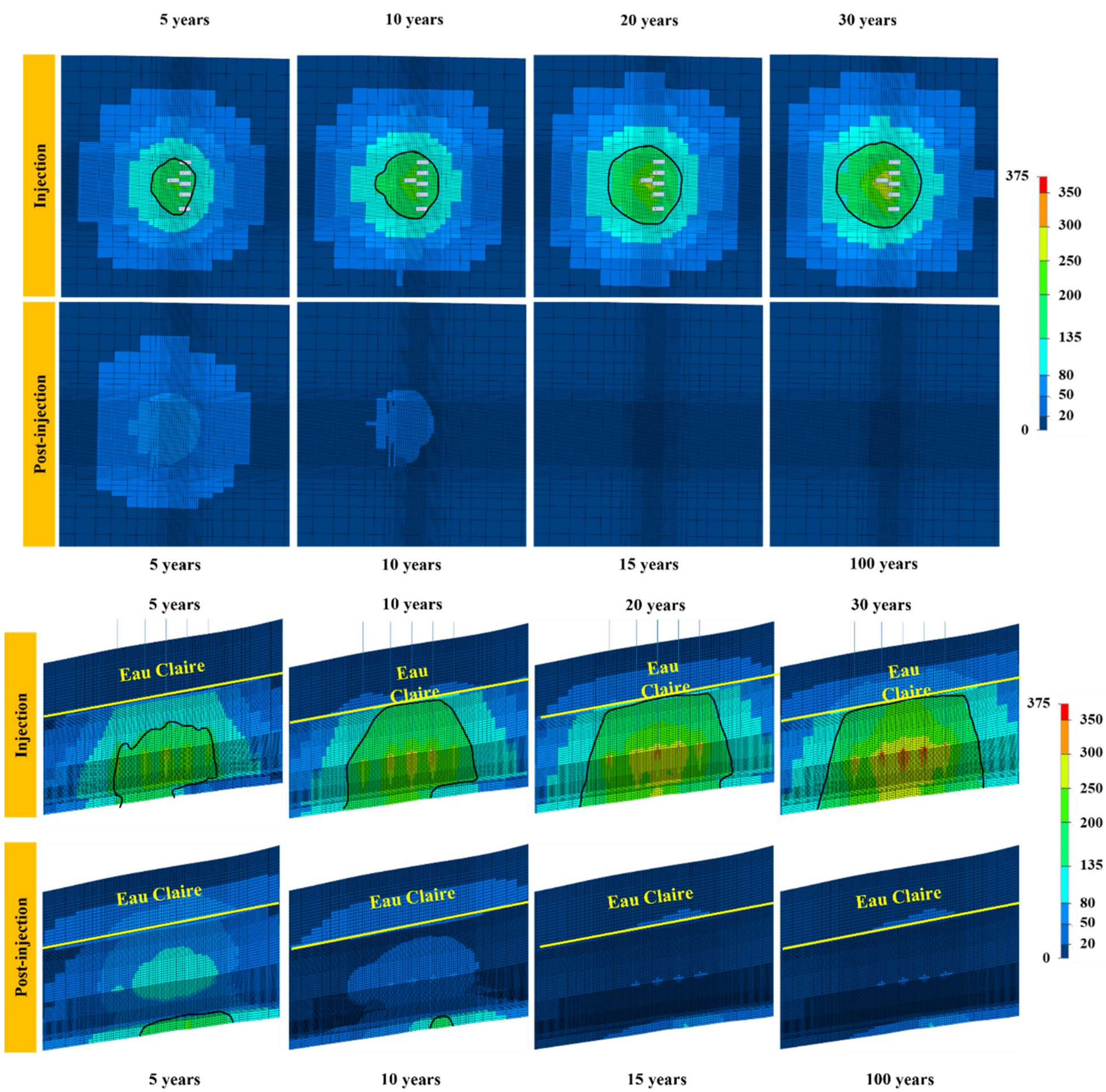
5 years
10 years
20 years
30 years
Injection
Post-injection
375
350
300
250
200
135
80
50
20
0
5 years
10 years
15 years
100 years
5 years
10 years
20 years
30 years
Eau Claire
Eau Claire
Eau Claire
Eau Claire
Injection
Post-injection
Eau Claire
Eau Claire
Eau Claire
Eau Claire
375
350
300
250
200
135
80
50
20
0
5 years
10 years
15 years
100 years

Figure 9-2. Pressure buildup in Mount Simon A Upper at layer 77 of model (upper) and in a S-N profile view through the injection wells (lower). The scale bar displays the pressure differential from pre-injection in psi.

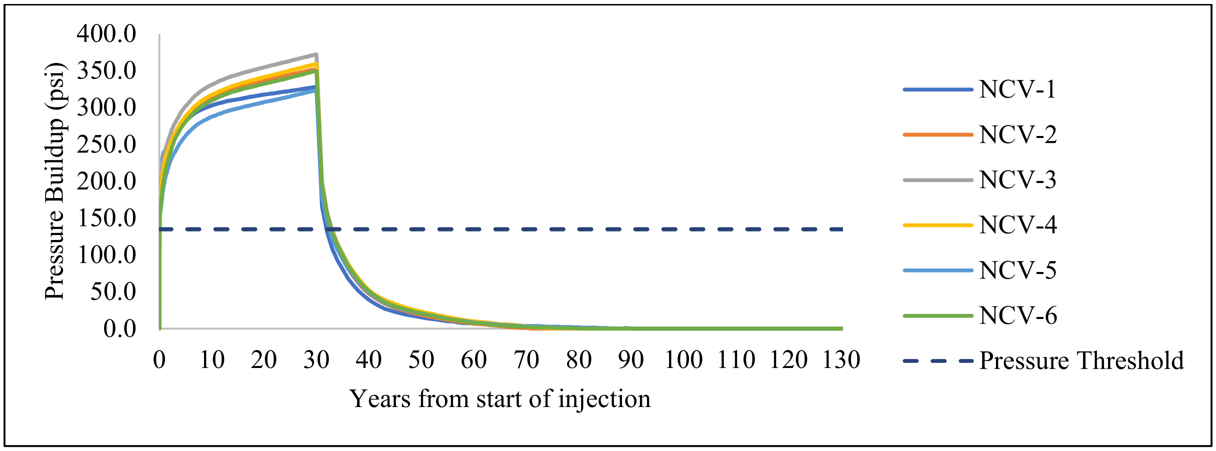

Figure 9-3. Graph illustrating the decline in Pressure differential in the injection wells following injection taken from the topmost perforation in each injection well.

9.3 Predicted Three-Dimensional Extent of the Free-Phase CO2 Plume and Associated Elevated Pressure Front at Site Closure

An alternate PISC timeframe of 15 years is proposed and described below. Computational modeling was used to determine the predicted extent of the CO_2 plume and pressure front at site closure pursuant to 40 CFR 146.93(a)(2)(ii). Geochemical trapping is not expected to occur at the project timeframes and was not included in the modeling. The map in **Figure 9-1** is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84 and shows the furthest extent of the pressure plume at the time of cessation of injection after 30 years of injection.

Figure 9-4 shows map and cross-section views of the modeled extent of the CO_2 plume during the injection and post-injection phases of the project. The simulated plume from site closure, 15 years after cessation of injection, to 100 years after cessation of injection shows only a 3% difference in plume area. The rate of change in area for the CO_2 plume from site closure to 100 years post injection is 0.04%/year.

Figure 9-3 and Figure 9-2 show the magnitude of the pressure differentials in the injection wells dissipating below the pressure threshold of 135 psi 5 years post-injection and down to 20 psi prior to site closure. Rapid pressure differential dissipation occurs in the reservoir with more gradual dissipation in the basement, overlying Mt. Simon C, and the Eau Claire caprock. Pressure differentials in the overlying caprock at site closure max out at 141 psi, which translates to a reservoir pressure of approximately 2,450 psi. The difference between site closure and 100-

year post-injection pressure differentials in the Eau Claire is 18 psi, which is approximately 0.2 psi/year. The gradual decrease in plume area and the pressure differential after 15 years post-injection indicates a stable storage system with little to no endangerment to the USDWs.

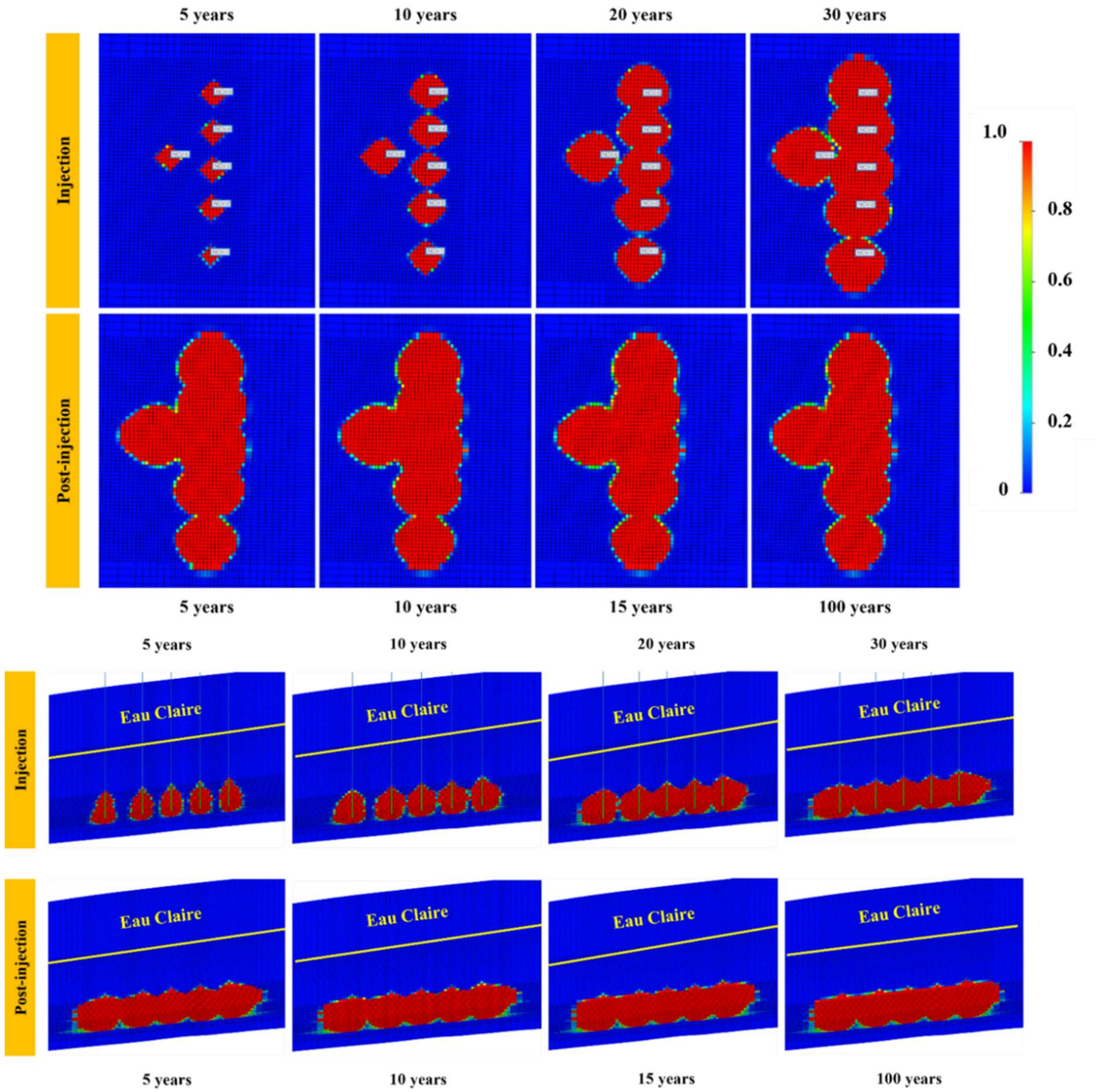

Figure 9-4. Gas saturation in layer 61 (Mount Simon B) during and following injection. The scale describes CO_2 saturation from 0% (blue) to 100% (red).

9.4 Post-Injection Monitoring Plan

Following the cessation of injection, all injection wells will be converted to monitoring wells and will continue to contribute monitoring data as they did during the injection phase of the project (**Figure 9-1**). No monitoring technologies will be added during the PISC phase of the project.

The post-injection phase will include monitoring for gas leaks in the wellheads and valves, external mechanical integrity testing, groundwater sampling, direct pressure and temperature measurements, and indirect and direct plume tracking. Every five years during the post-injection phase of the project, the monitoring data will be incorporated into computational models and the monitoring plan will be reviewed and updated, if needed, based on modeling results. Details on the specific technologies utilized and frequency for monitoring strategies pursuant to 40 CFR 146.93(a) (iii) is provided in **Table 9-1** below. Please refer to the Testing and Monitoring Plan for more detailed information on the testing and monitoring technologies.

The monitoring strategy utilizes a fixed frequency schedule to collect data. A *Quality Assurance and Surveillance Plan* (QASP) for all testing and monitoring activities is provided in the appendix to the *Testing and Monitoring Plan*. HGCS plans to secure options for rights to surface access across the entire project AoR for the whole duration of the project. In-well monitoring technologies will be implemented until the start of each well's plugging and abandonment procedure. All PISC monitoring technologies will be implemented for a minimum of 50 years or according to the Director approved alternate post-injection site care timeframe as proposed below.

Table 9-1. PISC Monitoring Strategy & Frequency.

Monitoring Category	Monitoring Method		Post-Injection Frequency (15 years)
Monitoring Plan Update	Reviewed every 5 years. Updated as required		As required
Mechanical Integrity Testing	*External*	Distributed Temperature Sensing	Continuous *(monitors)*
Groundwater Quality and Geochemistry Monitoring (Above-Zone)	Above-Zone & Shallow Groundwater Fluid sampling		*1 in 5 years
Direct Pressure Monitoring	Electronic P/T gauges		Continuous
Indirect Plume Monitoring Techniques	*Fiber/Wireline*	DTS-DAS	Continuous
		PNC Logging	1 in 5 years
	Seismic	Timelapse 3D DAS-VSP Surveys	1 in 5 years

9.4.1. Mechanical Integrity Testing

Continuous external mechanical integrity testing will continue to be implemented using DTS as outlined in the Testing and Monitoring Plan for all in-zone monitoring wells.

9.4.2. Monitoring Above the Confining Zone

The Ironton formation and shallow groundwater zones will be monitored to ensure protection of the USDWs within the AoR. Monitoring the Ironton formation, the first permeable unit above the confining zone, will provide early detection of any out-of-zone CO_2 movement prior to reaching the lowermost USDW aquifer. Additional monitoring in the shallow USDWs will allow for detection of a shallower leak should a leak occur above the Ironton formation or not be detected within the Ironton formation. Two methods will be conducted to monitor above-zone formations: PNC logging and groundwater sampling and analysis.

Groundwater sampling and analysis during the post-injection phase of the project will be conducted in the Ironton formation and shallow drinking water aquifers every 5 years. The first samples will be taken five years after cessation of injection and the last samples taken prior to site closure or prior to well plugging and abandonment, whichever comes first. The samples will be analyzed for water quality and indicators of CO_2 or brine movement. Should a leak be detected and verified in the above-zone Ironton formation a PNC log will be run to help quantify the vertical concentration of the CO_2 within the well it was detected.

Table 9-2 presents the monitoring methods, locations, and frequencies for monitoring groundwater quality and geochemistry above the confining zone. The fluid sampling will be conducted in the manner described in the Testing and Monitoring Plan with sample analytes removed or added based on baseline and injection phase groundwater monitoring results. More explicit detail for the groundwater analytical parameters is presented in the Testing and Monitoring Plan and QASP sections of this permit.

Table 9-2. Monitoring of groundwater quality and geochemical changes.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
Shallow Groundwater	Fluid Sampling	NCV OB SG 1-17	1 in 5 years
Ironton	Fluid Sampling	NCV OB I 1-6	1 in 5 years

9.4.3. Carbon Dioxide Plume and Pressure Front Tracking

HGCS will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure, and demonstration that no leakage of CO_2 is occurring, as specified in the Testing and Monitoring Plan, pursuant to 40 CFR 146.93(b). **Table 9-1** describes the monitoring methods and frequencies HGCS will implement in post-injection phase of the project. Locations of monitoring technologies as presented in the Testing and Monitoring Plan will remain the same with additional monitoring technology detail presented in the QASP. At a minimum, quarterly bottom-hole pressure and temperature measurements will be recorded during the post-injection phase of the project using Baker Hughes SureSENS QPT Elite permanent downhole gauges or equivalent. These gauges will continuously measure pressure and temperature data representative of the conditions of the uppermost perforated zone in all in-zone monitoring well locations. The DTS fiber optic cables will continue to record variations in temperature in the borehole to help track the vertical CO_2 plume within each in-zone well and to help constrain the lateral CO_2 plume extent within the AoR. . PNC logging will occur in the in-zone wells within the maximum CO_2 plume extent once every five years to quantify vertical CO2 concentration and location within the wells. Timelapse 3D DAS-VSP CO_2 plume imaging will occur once every five years to obtain better constraints on the 3D CO_2 plume extent between wells. The post-injection phase monitoring data will be incorporated into the computational model that will inform HGCS of plume movement and ultimately demonstrate plume stabilization.

9.4.4. Schedule for Submitting Post-Injection Monitoring Results

Additionally, pursuant to 40 CFR 146.91(e), included is a proposed schedule for submitting post-injection site care monitoring results to the Program Director. All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to the Program Director in reports submitted every five years. The data collection will be assembled and submitted to the Program Director by April 1st for the previous 5 years (ex. 2025 PISC monitoring data will be submitted by April 1st, 2030). The reports will contain information and data generated during the reporting period, i.e., well-based monitoring data, sample analysis, and the results from updated site models.

9.5 Alternative Post-Injection Site Care Timeframe

HGCS will conduct post-injection monitoring for 15 years following the cessation of injection operations. A justification for this alternative PISC timeframe is provided below. Regardless of the alternative PISC timeframe, monitoring, and reporting as described in the sections above will continue until HGCS demonstrates, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the project does not pose an endangerment to any USDWs, per the requirements at 40 CFR 146.93(b)(2) or (3).

9.5.1. Computational Modeling Results

Computational modelling across the HGSS for the PISC-SC period is the same model as the injection phase computational modelling as described in the AoR and Corrective Action Plan. Modeling is conducted for 30 years of injection and 100 years post-injection. Baseline and monitoring data will be incorporated into the model to track and predict the plume and pressure front evolution. Results appear isotropic due to the lateral continuity of the static earth model (SEM) and the lack of any known flow barriers that would impede fluid and pressure propagation. Due to these factors, the plume and pressure front migration is predictable and illustrated in **Figure 9-2**, **Figure 9-3**, and **Figure 9-4**.

Based on the computational modeling of the pressure front in the sequestration zone as part of the AoR and Corrective Action Plan, pressure at the injection well is expected to stabilize 15 years after the cessation of injection, as described. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and in the AoR and Corrective Action Plan.

As described in the Predicted Three-Dimensional Extent of the Free-Phase CO_2 Plume and Associated Elevated Pressure Front at Site Closure sections above, the simulated plumes from site closure, 15 years after cessation of injection, to 100 years after cessation of injection show only a 3% difference in plume area. The rate of change in area for the CO_2 plume from site closure to 100 years post injection is 0.04%/year. Based on the computational modeling, the pressure differentials in the injection wells dissipate to zero prior to site closure.

The AoR and Corrective Action Plan describes the performed sensitivity analysis performed in detail, which indicates that the proposed 15-year PISC timeframe is beyond the upper limit of time needed for the pressure buildup differential to fall below the threshold value of 135 psi. The varied parameters include:

- Rock compressibility,
- Gas hysteresis parameter,
- Fluid salinity, and
- Vertical permeability anisotropy

All of these values were varied +/- 50% from their base values, except for vertical permeability anisotropy which varied from -50% to 100%. The parameter that had the largest impact on the gas plume area and project AoR was fluid salinity. Despite the variation in fluid salinity, even the high case scenario resulted in pressure buildup falling below the threshold pressure before 8 years post-injection. For more details on the sensitivity analysis, please refer to the AoR and Corrective Action Plan.

9.5.2. Predicted Timeframe for Pressure Decline

The pressure declines rapidly following the cessation of injection, as described above in the Pre- and Post-Injection Pressure Differential section. **Figure 9-2** illustrates the lateral extent of the pressure front and demonstrates the pressure front stabilization prior to 15-years post-injection. Pressure decline is homogeneous throughout the reservoir. The sensitivity analysis indicates that the modeled pressure front is most sensitive to fluid salinity, but the variation of the parameter by 50% above and below the base value does not extend the time needed for the pressure differential to fall below the threshold value.

9.5.3. Predicted Rate of Plume Migration

The CO_2 plume migration is predicted to stabilize 15-years post-injection. **Figure 9-4** illustrates the lateral and vertical extent of the free-phase plume. As the figure displays, the plume stabilizes by the 15-year post-injection timeframe proposed. From the rate of change of plume area from the cessation of injection to 100-years post-injection is 0.04%/year. Notably, there is no noticeable change in the lateral plume geometry after 5 years post-injection. The maximum modeled plume extent occurs after 100-years post-injection, but the increase in area is less than 10% of the AoR or 26 square miles (mi^2). The vertical migration that occurs after the cessation of injection is confined to the Mt. Simon B, with very little to no interaction with the Mt. Simon C. Overall, the migration of the plume slows drastically 5-10 years post-injection and is small and predictable at the proposed end of PISC, 15-years post-injection.

9.5.4. Site-Specific Trapping Processes

The current version of the HGSS dynamic reservoir model modeled the following trapping processes:

- Structural trapping as modeled by including the Eau Claire confining layer
- Residual trapping as modeled by relative permeability hysteresis using a maximum critical gas saturation of 0.4; value estimated by using CMG GEM manual as stated in the *Computational Modeling Details* document.
- Dissolution trapping as modeled by Henry's law

Please refer the *AoR and Corrective Action Plan* as well as the *Computational Modeling Details* documents for details on the implementation of these trapping mechanisms. The current model does not include mineral trapping processes. While there is evidence of mineral trapping and mineralization of injected CO_2, these reactions are anticipated to occur over the project timeframe. Please refer to the *Project Narrative* for further explanation on the relevance of geochemical interactions at HGSS.

Figure 9-5 shows the relative distribution of injected CO_2 into supercritical CO_2, and trapped CO_2 as indicated by dissolved and residually trapped portions. As the figure indicates, majority of injected CO_2 is in a supercritical phase, some of which is trapped residually. As expected, during the injection phase, a portion of the injected CO_2 dissolves in the formation brine while the rest of it remains in a bulk supercritical phase. Upon cessation of injection, the solubility process becomes less dominant compared to the residual trapping process wherein the free phase CO_2 attempts to redistribute within the reservoir and encounters hysteresis as the wetting water phase in the reservoir invades the CO_2 filled pores.

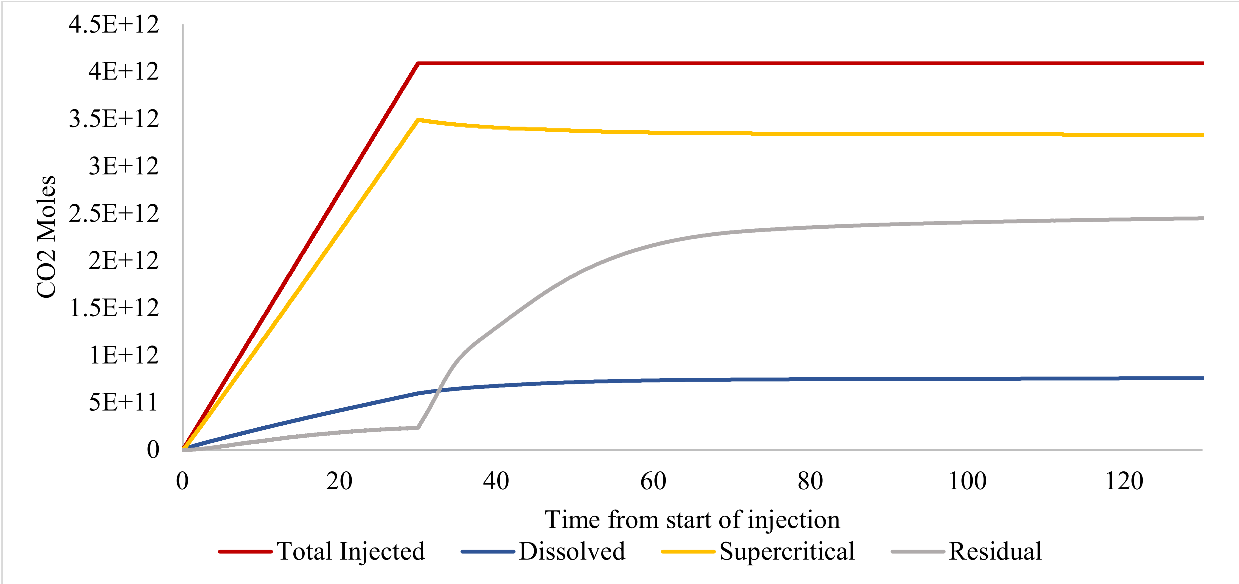

Figure 9-5. Relative distribution of injected CO2 into supercritical, dissolved, and residually trapped phases and their evolution over time.

9.5.5. Confining Zone Characterization

The Eau Claire Formation is the confining zone at the Heartland Greenway Storage Site (HGSS) and is composed of shale, siltstone, and sandstone. The depth to the top of the Eau Claire is approximately 4,950 feet and the Formation is approximately 540 feet thick. The Eau Claire Formation is recognized as a regional seal for the Mt. Simon across the Midwest and interactions with brine-impregnated CO_2 and the caprock may reduce permeability through precipitation of carbonates and clays or mobilization of clay particles[1]. Average zone permeability in the Eau Claire Formation is 2.9 millidarcy (mD) and average zone porosity is 5.9%. Based on the low permeability and porosity of the confining zone and the thick sequence of lower permeability strata of the Upper Mt. Simon, there is no anticipated interactions between the confining zone and the CO_2 plume. For more information on the geologic characterization, please refer to the Application Narrative.

Computational modeling conducted for the HGSS illustrates that the Eau Claire Formation inhibits the pressure front from migrating upward (**Figure 9-2**). As discussed, the Upper Mt. Simon is predicted to fully contain the free-phase CO_2 plume as illustrated in **Figure 9-4**. Despite the barrier to vertical migration, the Eau Claire is impermeable enough to act as a geological trap. As project wells are drilled, logged, and cored, more data will become available and will be utilized to update the Static Earth Model (SEM) and to inform computational modeling.

[1] Liu, F., Lu, P., Griffith, C., Hedges, S. W., Soong, Y., Hellevang, H., & Zhu, C. (2012). Co2–brine–caprock interaction: Reactivity experiments on Eau Claire Shale and a review of relevant literature. International Journal of Greenhouse Gas Control, 7, 153–167. https://doi.org/10.1016/j.ijggc.2012.01.012

9.5.6. Assessment of Fluid Movement Potential

There are no wells within the project AoR that penetrate the confinement interval except for the proposed project wells which will be completed to Class VI standards as described in the *Project Narrative*. This includes corrosion resistant materials for components of the injection wells that will contact the injectate, including CO_2 resistant cement and tubulars. Based on these factors, along with the favorable geological setting, migration of fluid out of the injection interval is extremely unlikely. For more details on well construction and plugging, please refer to the *Injection Well Construction* section of the Application Narrative and the *Injection Well Plugging Plan*.

9.5.7. Location of USDWs

The USDWs that exist near the HGSS are shallow sand and gravel aquifers that act as water sources for nearby populations.[2] [3] Although most groundwater in the area is withdrawn from shallow unconsolidated formations, it is expected that the St. Peter Formation could be the deepest USDW; locally it is not tapped for human use. HGSS's injection zone at the top of the Mount Simon B is vertically separated from the deepest overlying USDW of the Saint Peter sandstone by 2,035 feet at the NCV-INJ 3 well, central to the AoR. Surficial aquifers in the region are located approximately 3 miles to the SE of HGSS and contain an approximate vertical distance from the injection zone of approximately 5,200 feet. The distance between and fluid properties of the injection zone and the lowermost USDW help determine the pressure threshold value, which delineate the project AoR as described in *the Computational Modeling Detail document*. The further the separation distance from the injection zone to the lowermost USDW the smaller the AoR. The large 2,035 separation translates to a higher pressure differential needed to allow CO_2 to migrate up an artificial penetration or other migration pathway to the Saint Peter sandstone.

The calculated pressure threshold value at HGSS is 135 psi using the Saint Peter sandstone as the lowermost USDW. Computational modeling shows that the pressure differential in the reservoir falls below 135 psi around 5 years after the cessation of injection meaning the pressures in the reservoir needed to allow flow through an artificial penetration or other conduit for fluid flow are not present. Therefore, reservoir pressures after 5 years pose little to no risk of USDW contamination. Furthermore, the vertical separation distance of approximately 570 feet between the injection zone and the caprock allow for lower pressure differentials at the base of the caprock as compared to the injection zone. This decreases the risk of fracture within the caprock due to elevated pressures in the reservoir. The vertical separation distance from the injection zone to the base of the caprock and the top of the caprock to the base of the lowermost USDW, the predicted reservoir pressure differential decreases below the calculated pressure differential threshold, and the stable predicted plume help demonstrate non-endangerment to shallow and the

[2] Midwest Technology Assistance Center, 2009, "Groundwater Resource Assessment for Small Communities: Groundwater Availability at Morrisonville, Illinois (Christian County)

[3] Burris, C.B., Morse, W.J., and Naymik, T.G., 1981, Assessment of a Regional Aquifer in Central Illinois, ISGS Cooperative Ground water Report 6

lowermost USDW's. Further detail on the region's aquifers can be found in the *Project Narrative*.

9.6 Non-Endangerment Demonstration Criteria

Prior to approval of the end of the post-injection phase, HGCS will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR 146.93(b)(2) and (3).

The owner or operator will issue a report to the UIC Program Director. This report will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Program Director to review the analysis. The report will include the following sections:

9.6.1. Introduction and Overview

A summary of relevant background information will be provided, including the operational history of the injection project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

9.6.2. Summary of Existing Monitoring Data

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and post-injection phases of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the UIC Program Director [40 CFR 146.91€], and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization [40 CFR 146.82(a)(6) and 146.87(d)(3)].

9.6.3. Summary of Computational Modeling History

A summary of the computational modeling conducted to determine the position of the pressure front and free-phase CO_2 plume during and following injection. Data used for modeling currently comes from the Illinois State Geological Survey (ISGS), the Illinois Basin Decatur Project (IBDP), Industrial Carbon Capture and Storage (ICCS) project, the FurtureGen2 program, and the CarbonSafe TR McMillen 2 well. The drilling and subsequent logging and coring has provided high-quality characterization of the storage reservoir and caprock which has informed computational modeling. Subsequent modeling for the non-endangerment demonstration will incorporate any additional site characterization data prior to injection and monitoring data up to the commencement of the non-endangerment demonstration. Throughout injection, CO_2 saturation and pressure plume monitoring data using PNC logging, 3D VSP, PT gauges, and DTS technologies will provide a wealth of data with which to history-match and update computational modeling. If there is a major disagreement between the computational modeling performed and the data acquired, re-evaluation shall take place to determine the discrepancies.

9.6.4. Evaluation of Reservoir Pressure

The reservoir pressure will be determined with baseline sampled and will continuously collect data in the injection and monitoring well throughout the injection process and during PISC. Pressure gauges will directly measure the reservoir pressure. This data will be utilized to re-evaluate the model every 5 years.

9.6.5. Evaluation of Carbon Dioxide Plume

The carbon dioxide plume will be resolved through analyzing the data collected from PNC logging, 3D VSP surveys, and DTS fiber optics. PNC logging and DTS data will be compared to modeled CO2 plume extent locations to determine the vertical extent of the plume and predicted concentrations at the wellbores. 3D VSP surveys and the distribution of PNC logging and DTS data across the AoR will resolve the lateral extent of the plume throughout and following injection during PISC.

9.6.6. Evaluation of Emergencies or Other Events

In the unlikely event of an emergency, the extensive data collection through monitoring as outlined in the Testing and Monitoring Plan and above in the PISC Monitoring Plan will be utilized to identify, locate, and remediate the emergency. The depth and salinity of the USDWs and injection interval, pressure and temperature gauges, and modeling are all utilized to perform baseline analysis of reservoir conditions that can be compared to data acquired during and following injection. Regular fluid sampling, pressure and temperature data, PNC logging, and 3D VSP surveys all will work in tandem to monitoring the pressure front and plume migration. This information will all be used as part of the AoR re-evaluation.

9.7 Site Closure Plan

HGCS will conduct site closure activities to meet the requirements of 40 CFR 146.93(e). Within 90 days of site closure, HGCS shall submit a site closure report. This report must be retained at a location designated by the Program Director for 10 years.

9.7.1. Site Closure Procedure

HGCS will notify the Program Director at minimum 120 days prior to site closure. Upon receiving authorization for site closure, all monitoring wells shall be plugged and abandoned

(P&A) as outlined in the *Site Closure Plugging Program*. A final Site Closure Plan will be submitted to the Program Director for approval with the notification of the intent to close the site. The following steps are to be used as a general guide during site closure.

1. Notify the Program Director and all relevant local, state, and federal government agencies of intent to close the project site.
2. Decommission equipment.
3. P&A all monitoring and related project wells.
4. Return well locations to pre-injection conditions including site reclamation, as necessary.
5. Complete and submit the Site Close Report to the Program Director within 90 days.

9.7.2. Equipment Decommissioning

The decommissioning of equipment will be completed in two stages: after the cessation of injection where equipment required to inject CO_2 is no longer necessary and at the end of the PISC period.

Step 1: After cessation of injection, surface equipment necessary to safely sequester CO_2 such as pumps, flowlines, flowmeter, annular pressure monitoring equipment, and piping and control equipment will no longer be necessary and shall be dismantled and removed from the HGSS.

Step 2: After the PISC period, surface equipment related to the monitoring activities demonstrated in this plan and as part of the PISC period outlined in the Testing and Monitoring Plan will be decommissioned. This includes the plugging and abandonment of all project wells, removal of surface facilities, and reclamation of the land to pre-injection conditions. The plugging and abandonment procedures are outlined below and are designed to ensure containment of the injected CO_2 and for protection of USDWs.

9.7.3. Site Closure Plugging Program

Once plume stabilization has been determined by CARB to have occurred, pursuant to 40 CFR 146.93(e), all CCS project wells will be abandoned following 40 CFR 146.92 of the Class VI Rule. Abandonment shall be performed to not allow the movement of injection or formation fluids out of the storage complex that endangers a USDW.

Prior to well plugging, the mechanical integrity of the wells will be verified by the distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) fiber optic systems emplaced in the monitoring wells. The well plugging and abandonment will follow the methodology described in the *Site Closure Plugging Program*, except CO_2-resistant cement need not be utilized in wells that do not encounter CO_2 at depth. Refer to the *Site Closure Plugging Program* for the well plugging procedure.

9.7.4. Site Restoration

At the direction of the Program Director, the HGCS will restore the site to a condition agreed to with the Program Director, as close to pre-injection conditions as possible. This includes removing surface equipment, road access, and any other facilities that remain on location. The preliminary vegetation type and density of the area will be utilized to ensure that pre-injection conditions are established.

9.7.5. Site Closure Report

Within 90 days of site closure, HGCS shall submit a site closure report. This report will be retained at a location designated by the Program Director for 10 years. The report will contain at minimum the following information:

- Plugging of the verification and geophysical wells (and the injection well if it has not previously been plugged),
- Location of sealed injection well on a plat of survey that has been submitted to the local zoning authority,
- Notifications to state and local authorities as required at 40 CFR 146.93(f)(2),
- Records regarding the nature, composition, and volume of the injected CO_2, and
- Post-injection monitoring records.

HGCS will record a notation to the property's deed on which the injection well was located that will indicate the following:

- That the property was used for carbon dioxide sequestration,
- The name of the local agency to which a plat of survey with injection well location was submitted,
- The volume of fluid injected,
- The formation into which the fluid was injected, and
- The period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by the owner or operator for a period of 10 years following site closure. Additionally, HGCS will maintain the records collected during the post-injection period for a period of 10 years after which these records will be delivered to the UIC Program Director.

9.8 <u>Quality Assurance and Surveillance Plan (QASP)</u>

The Quality Assurance and Surveillance Plan is presented in the Appendix of the Testing and Monitoring Plan.